Raquel J. Webster
Senior Counsel

May 11, 2018

BY HAND DELIVERY AND ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4809 - 2019 Standard Offer Service Procurement Plan
2019 Renewable Energy Standard Procurement Plan
Responses to Division Data Requests – Set 1

Dear Ms. Massaro:

On behalf of National Grid,[1] I am enclosing the Company's responses to the Rhode Island Division of Public Utilities and Carriers (Division) Data Requests 1-2 and 1-3 in the above-referenced docket.

Please note that the Company is seeking protective treatment of Confidential Attachments DIV 1-2-2 (a) through (f) and Confidential Attachment DIV 1-3, as permitted by PUC Rule 1.2(g) and by R.I. Gen. Laws § 38-2-2(4)(B). This filing also contains a Motion for Protective Treatment in accordance with PUC Rule 1.2(g) and R.I. Gen. Laws § 38-2-2(4)(B). In compliance with Rule 1.2(g), National Grid is providing a USB Flash Drive containing the confidential versions of Attachments DIV 1-2-2 (a) through (f) and Attachment DIV 1-3 in a sealed envelope marked, **"Contains Privileged and Confidential Materials – Do Not Release."**

Thank you for your attention to this transmittal. If you have any questions, please call me at 781-907-2121.

Very truly yours,

Raquel J. Webster

Enclosure

cc: Docket 4809 Service List
Leo Wold, Esq.
John Bell, Division

[1] The Narragansett Electric Company d/b/a National Grid.

40 Sylvan Road, Waltham, MA 02451
T: 781-907-2121 ■ raquel.webster@nationalgrid.com ■ www.nationalgrid.com

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

2019 Standard Offer Supply Procurement Plan and
2019 Renewable Energy Standard Procurement Plan **Docket No. 4809**

NATIONAL GRID'S REQUEST
FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] respectfully requests that the Rhode Island Public Utilities Commission (PUC) provide confidential treatment and grant protection from public disclosure certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by PUC Rule 1.2(g) and R.I. Gen. Laws § 38-2-2(4)(B). National Grid also respectfully requests that, pending entry of that finding, the PUC preliminarily grant National Grid's request for confidential treatment pursuant to Rule 1.2 (g)(2).

I. BACKGROUND

On May 11, 2018, National Grid filed with the PUC its responses to the Rhode Island Division of Public Utilities and Carriers' (Division) Data Requests Nos. 1-2 and 1-3. In Data Request 1-2, the Division requests the Excel spreadsheets that reflect the analysis of capacity risk premiums included in the standard offer service (SOS) bids that was prepared by the Company's consultant, Concentric Energy Advisors, Inc.. In response to Division Data Request 1-2, the Company has provided the Division with a USB Flash Drive containing a confidential PowerPoint file and confidential Excel files, identified as Attachments DIV 1-2-2(a) through (f).

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[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

Attachments DIV 1-2-2(a) through (f) provide the analysis of capacity risk premiums included in the January 2018 SOS request for proposal (RFP). In Data Request 1-3, the Division requests the tables that appear on pages 9 and 10 of the testimony of Company Witness, Stephen A. McCauley in native format and, as applicable, in Excel format with formulae intact. In response to Data Request 1-3, the Company has provided the Division with the confidential Excel versions of the tables presented on pages 9 and 10 of the Direct Testimony of Stephen A. McCauley. These tables are identified as Confidential Attachment DIV 1-3. National Grid respectfully requests that the PUC afford confidential treatment to confidential PowerPoint file and Excel files contained on the USB Flash in its response to Division Data Requests 1-2 and 1-3.

II. LEGAL STANDARD

The PUC's Rule 1.2(g) provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1 *et seq.* Under the APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I. Gen. Laws § 38-2-2(4). Therefore, to the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of APRA to deem such information to be confidential and to protect that information from public disclosure.

In that regard, R.I. Gen. Laws § 38-2-2(4)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where disclosure of information would likely (1) impair the Government's ability to obtain necessary information in the future; or (2) cause substantial harm to the competitive position of the person from whom the information was obtained. Providence Journal Company v. Convention Center Authority, 774 A.2d 40 (R.I. 2001).

The first prong of the test is satisfied when information is voluntarily provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. Providence Journal, 774 A.2d at 47.

III. BASIS FOR CONFIDENTIALITY

The Company requests confidential treatment of the unredacted versions of Attachments DIV1-2-2(a) through (f) because these attachments include the analysis of capacity risk premiums included in the January 2018 Standard Offer Service RFP. The information in Attachments DIV 1-2-2(a) through (f) reflects the work product and analysis that the Company's consultant, Concentric Energy Advisors, Inc. prepared, and this information is commercially sensitive, commercially valued, and proprietary. Disclosing this information to the public will put the Company's consultant at a competitive disadvantage in their industry if the requested work papers, related spreadsheets, or formulae are disclosed to the public. The Company requests confidential treatment of the information contained in the un-redacted version of the excel versions of the tables in Attachment DIV 1-3 because these files include pricing information, which is commercially sensitive and proprietary. Disclosing this pricing information to the public could be commercially harmful to the nonregulated power producers and their customers because competitors could use this information in such a way that could impede the nonregulated power producers' ability to compete in the future. Moreover, disclosure of this information could adversely affect the balance of the retail energy markets.

IV. CONCLUSION

Accordingly, the Company respectfully requests that the PUC grant this motion for protective treatment of Attachments DIV 1-2(a) through (f) and the Excel version of Confidential Attachment DIV 1-3.

WHEREFORE, the Company respectfully requests that the PUC grant this Motion for Protective Treatment of Confidential Information.

Respectfully submitted,

NATIONAL GRID

By its attorney,

Raquel J. Webster

Raquel J. Webster (RI Bar #9064)
National Grid
40 Sylvan Road
Waltham, MA 02451
(781) 901-2121

Dated: May 11, 2018

Division 1-2

Request:

Please provide the analysis of capacity risk premiums included in the SOS bids performed by Concentric Energy. Included are any relevant workpapers in Excel spreadsheets with formulae and links intact.

Response:

Please see Attachment DIV-1-2-1 which is a report authored by Concentric Energy Advisors, Inc. (Concentric) entitled Rhode Island Full Requirements Service Risk Premiums.

Please see the confidential Attachments DIV 1-2-2(a) through (f), which is the analysis of capacity risk premiums included in the January 2018 Standard Offer Service RFP. The Company recommends first reviewing the PowerPoint Flow Charts, identified as Attachment DIV 1-2-2(a) to determine the interactions of the various Excel spreadsheets. The Company also offers a technical conference call with Concentric to discuss the analysis.

Pursuant to PUC 1.2(g), the Company is seeking confidential treatment of Attachments DIV 1-2-2 (a) through (f).

Rhode Island Full Requirements Service Risk Premiums

May 2018

Contents

Introduction

In January 2018, Concentric Energy Advisors, Inc. ("Concentric") was retained by National Grid USA Service Company, Inc. ("National Grid") to perform quantitative analysis pertaining to the risk premiums associated with energy suppliers providing fixed capacity prices included in Full Requirement Service ("FRS") transactions. National Grid's Request for Proposal ("RFP") for Full Requirements Service requires suppliers to provide fixed prices for the components of electric service, but it also requires the suppliers to bear the economic consequences if the cost to serve the load fluctuates.[1] Therefore, in addition to the cost of the electric service components, suppliers will add premiums to the cost of the electric service to address this potential variability. This report summarizes the work to estimate these risk premiums.

The cost to serve the load may fluctuate by the very nature of the Standard Offer Service ("SOS"). The SOS is the service for those electric customers who are not taking electric supply from a competitive supplier. No matter what the quantity or cost to serve it, the SOS supplier commits to provide a fixed percentage of the SOS load for a fixed unit price. Due to this structure the SOS supplier must manage both price and load risk. In addition to load fluctuations due to weather the SOS supplier's load can change because of customers migrating to and from SOS and economic expansions and contractions. Additionally, other cost components may fluctuate as a function of how the SOS load coincides with the aggregate system load. The SOS supplier commits to a fixed price expressed in $/MWh for all the services; however, not all component costs are incurred in those units.[2]

The risk premium for a fixed capacity price included in the FRS was calculated by analyzing the individual components' costs in FRS and modeling the economic consequences of changes to the cost to serve the load. The approach involved calculating the risk for each individual component and the compounded risk of serving all unknown cost fluctuations. The approach utilizes modern portfolio theory ("MPT"), which estimates the risk of a portfolio as a non-linear combination of its elements and is implemented by Option pricing theory.[3] The resulting quantitative analysis replicates how a SOS supplier might calculate a price associated with the incurred risk as part of its response to an FRS RFP. The analysis differentiates the sources of risk and considers the aggregation of risk across different customer classes that are solicited in the FRS RFP. The risk premium analysis shows that the total risk premium for FRS transactions could be diminished if the procurement of FRS is limited to energy and ancillary services only. The capacity component may be charged by the SOS supplier at cost without any markup for margin or risk.

Concentric Energy Advisors is a consulting energy firm with more than 60 employees and offices in Calgary, Alberta; Marlborough, MA, Washington, DC and Chicago, IL. It specializes in management consulting and financial advisory services with a focus on the North American energy industry. Its industry experts have held positions with utility companies, regulatory agencies, integrated energy companies, regional transmission organization, retail marketing companies and utility management consulting firms. Concentric is involved in all aspects of wholesale

[1] National Grid procures energy, ancillary services, and capacity from SOS suppliers. The SOS supplier is also responsible for miscellaneous charges from the Independent System Operator-New England ("ISO-NE").
[2] Namely capacity in the market is priced in $/MW-month to reflect the cost of maximum consumption (i.e. peak demand) over a month. Energy and ancillary services are priced per unit of energy consumed. Translating the price of capacity into $/MWh therefore involves spreading the cost of that capacity over the number of units (MWh) consumed over the same period. The result is challenging because it is forcing a relationship between energy consumed (MWh) to a product that is only priced in terms of the maximum level consumed over the month ($/MWh-month).
[3] The approach was originally developed in 1952 by Economist Harry Markowitz and was later awarded a Nobel Prize in economics in 1990. See Markowitz, H.M. (March 1952). "Portfolio Selection". The Journal of Finance. 7 (1): 77–91.

market design and has significant experience assisting utilities, independent power producers, and government entities in shaping and understanding wholesale electric market design, risk management and operational issues. Our expertise includes energy and capacity market design and development; price formation analysis; market power analysis; ancillary services price determination and settlement procedures; transmission system operations; access, pricing and expansion; and power system reliability and operations standards.

Admittedly, the techniques utilized in the analysis reflect quantitative methods that may be considered as elaborate and requiring above-average familiarity with these topics. The Report however tries to avoid getting into the technical details of the technique as much as possible and is written with a non-technical audience in mind. The exposition of topics focuses more on the intuition, and less on the technical details.

Background

National Grid (doing business in Rhode Island as The Narragansett Electric Company) is required to provide electric supply to customers in its Rhode Island territory who are not taking electric supply from a competitive supplier.[4] This service is known as Standard Offer Service. To satisfy this obligation, National Grid conducts competitive procurement of Full Requirement Services from wholesale suppliers and through spot market purchases. When a SOS supplier provides services under FRS, it is required to satisfy National Grid's load obligations without any minimum or limit on quantity or price variations. For a fixed $/MWh price, the supplier becomes responsible for the energy, capacity, ancillary services and miscellaneous ISO-NE charges associated with the SOS customer load.

Annually, National Grid requests the Rhode Island Public Utilities Commission ("PUC") to approve a Standard Offer Service Procurement Plan ("SOS Plan"). The annual SOS Plan, except for minor changes, is essentially the same each year. The SOS Plan employs a laddered and layered repeating procurement schedule for the residential and commercial groups months in advance and purchases 10% of requirements at market (i.e. spot). First introduced in the 2011 SOS Procurement Plan, this is the preferred procurement method because the transactions are dollar-cost averaged to create a blended supply rate.[5] In Order No. 22677, the PUC concluded that the SOS Plan achieves several goals: 1) Mitigates volatility for smaller customers; 2) Diminishes risks associated with wholesale procurement and the price shock associated with those risks; and 3) Reflects market price signals through seasonal rates, to some extent, for all customer groups; as well as encourage conservation and energy efficiency measures[6].

National Grid issues RFPs on a quarterly basis to supply firm, load-following electric supply to meet the SOS requirement.[7] The competitive solicitations include transactions for groups of customers (Residential, Commercial, and Industrial) with different transaction lengths.[8]

[4] Rhode Island General Laws § 39-1-27.3
[5] Docket No. 4149
[6] Order No. 22677 at p. 7.
[7] See http://www.nationalgridus.com/energysupply/
[8] Residential: Rate Class A-16 and A-60; Commercial: G-02, C-06, S-06, S-10, S-14; Industrial: G-32, B-32, G-62, B-62 and X-01.

Full Requirement Service

Under SOS, National Grid procures energy, capacity, and ancillary services associated with the SOS customer load. As of the January 9th, 2018 and looking out 12 months into the future, approximately 46% of FRS charges are for energy, 1% for ancillary services, and approximately 53% for capacity.[9] These components can be defined as follows:

1. Energy ($/MWh). Refers to the amount of electrical power used or the level of electricity consumption at a time, measured in megawatts.
2. Ancillary services ($/MWh). Services that ensure the reliability of and support for the transmission of electricity to serve load, including regulation and frequency response (regulation or automatic generator control), spinning reserve, non-spinning reserve, replacement reserve, and reactive supply and voltage control.[10]
3. Capacity ($/MW-month). Refers to the rated and continuous load-carrying ability, expressed in megawatts or megavolt-amperes, of generation, transmission, or other electrical equipment. Capacity payments allow generators to ensure the long-term availability of sufficient generation capacity for the reliable operation of the bulk power grid.

When a SOS supplier responds to a FRS RFP, it supports its bid with assets it already owns or by purchasing products that align with the commitments it makes with National Grid. For energy, the supplier will either use the output from generation it owns or will purchase it in advance in wholesale markets. Ancillary services products are typically paid at market (given its small size) and capacity is purchased at market prices that are established through the Forward Capacity Market ("FCM"). More specifically, a SOS supplier will support its bid by participating in the following markets:

1. Forward Energy Markets. These are established markets for electricity for peak and off-peak hours.[11] Participants can negotiate prices for electricity up to 5 years in advance through energy Futures at markets such as the Chicago Mercantile Exchange or Intercontinental Exchange, and up to 9 years in advance through Forwards in the over-the-counter market.[12] For both Futures and Forwards in Rhode Island, liquidity is dramatically lower in deals for periods over 8 months before expiration in visible markets, but liquidity may extend through an 18-month period in the over-the-counter market where volume is not reported.
2. Forward Capacity Market. This is a market whereby the ISO-NE establishes a price for generating resources through an auction mechanism. The Forward Capacity Auctions ("FCA") are held annually, three years in advance of the capacity period. Resources compete in the auctions to obtain a commitment to supply capacity in exchange for market-priced capacity payments.[13]

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[9] The average cost from April 2018 through March 2019 as of Jan 9, 2019 was $88.41/MWh. This represents the sum of $40.59/MWh for ATC energy (46%), $0.726/MWh for Ancillaries (1%) and $47.10/MWh for capacity (53%).

[10] https://www.iso-ne.com/participate/support/glossary-acronyms

[11] In New England, peak hours refer to the hours between 7:00 a.m. and 11:00 pm on nonholiday weekdays. The combination of peak and off-peak prices to estimate a price around-the-clock ("ATC") is estimated by combining peak (56%) and off-peak (44%) prices.

[12] Chicago Mercantile Exchange: http://www.cmegroup.com/trading/energy/electricity/nepool-rhode-island-5-mw-peak-calendar-month-day-ahead-swap-futures_contract_specifications.html; Intercontinental Exchange: https://www.theice.com/products/53168994/ISO-New-England-Rhode-Island-Day-Ahead-Peak-Fixed-Price-Future; and for over the counter example see http://otcgh.com/

[13] https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/

3. Ancillary services markets. Various ancillary services markets are administered by ISO-NE for supporting and ensuring short-term reliability of the power system.[14]

For a supplier, committing to a $/MWh price that combines energy, ancillary services and capacity is complicated because energy and ancillary services are priced as a function of consumption ($/MWh), whereas capacity is priced as a function of historical annual SOS peak coincident with the ISO-NE system peak ($/MW-month). Offering a $/MWh equivalent for capacity is more complicated than for energy and ancillary services, and thus may result in additional risk premium or decreased RFP participation.

The results of the quantitative analysis provide opportunities to lower customer costs by changing the FRS product. Excluding capacity from the FRS procurement process may decrease the total risk premiums SOS suppliers are adding to their bid prices in a RFP submittal. In addition, excluding capacity from the FRS RFPs may increase the number of suppliers interested in providing these services because capacity costs would be passed through to customers at cost and at no risk to the suppliers. By excluding capacity from the FRS, capacity will be treated in a similar way that transmission service is today. National Grid is billed by ISO-NE and recovers these transmission costs from the retail customers.

Nature of the Risk Premium

With FRS the SOS supplier commits to serve the load at a fixed $/MWh irrespective of the actual quantity of load to be served or the actual cost to serve it. To compensate for the uncertainty of the true cost of serving the load, the supplier will add a premium to its cost (the risk premium) to account for the variability it may encounter. The sources for the variability can be summarized as follows:

Changes to Quantity

The quantity to serve fluctuates primarily as a function of weather but it affects customer groups differently. Figure 1 illustrates weather's effect on load. Weather affects residential consumption more than the other customer groups. Figure 2 displays the hourly and monthly seasonality of each customer group. There are several items that are worth noting from these two Figures:

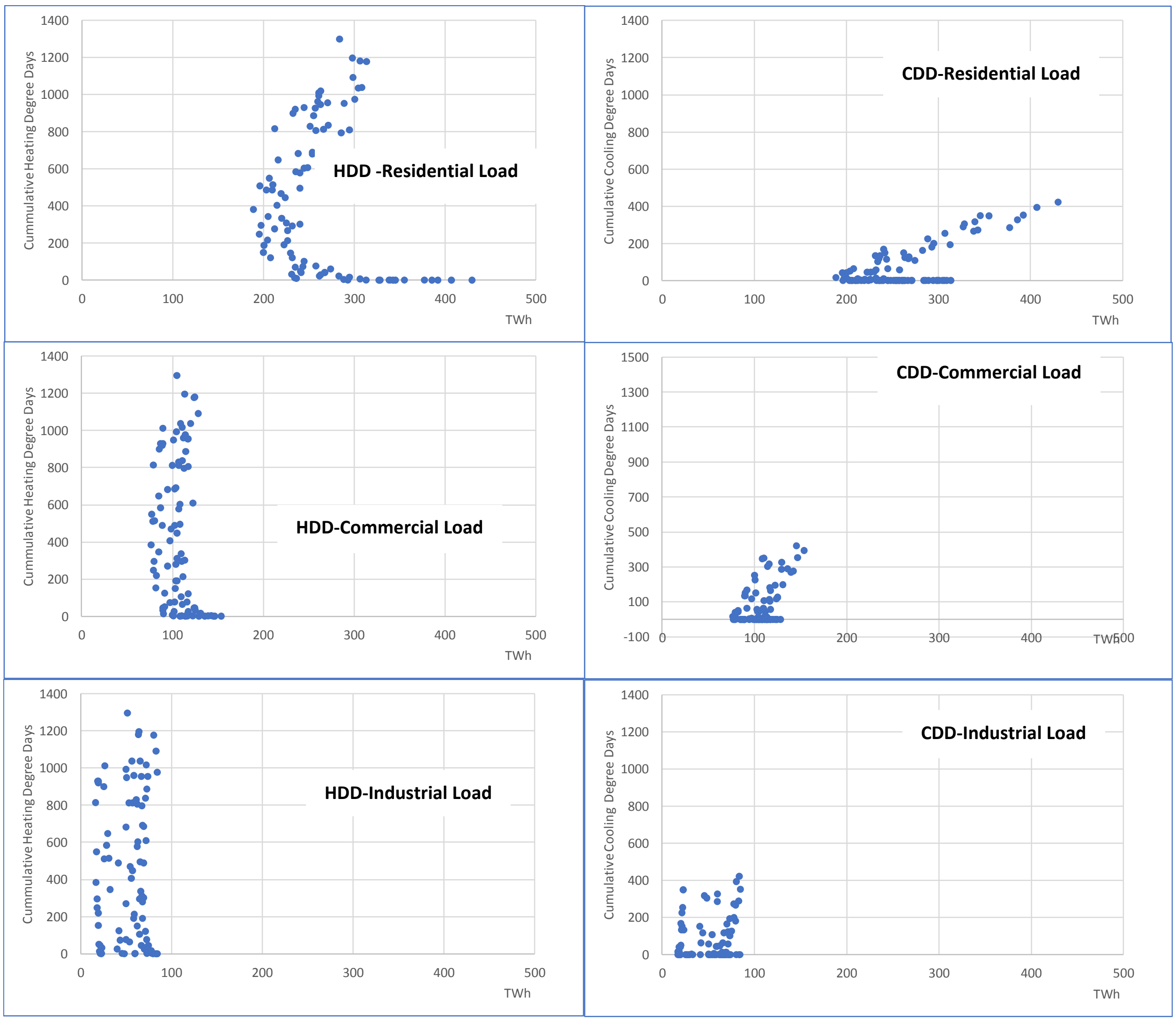
1. Residential load is more sensitive to changes in weather than to prices. For a SOS supplier, this means that the risk of residential load to weather increases as weather deviates from normal, but it is somewhat predictable. The residential load has limited capabilities to substitute sources for heating or cooling (e.g. if the temperature is warmer, residential load will increase);
2. Industrial and commercial loads are not as sensitive to changes in weather as residential load. For a SOS supplier this is attractive because energy prices tend to be highest when weather is most extreme;
3. A SOS that serves multiple customer groups can diversify its risk. A supplier that can serve more than one group of customers can shape the aggregate consumption pattern to reduce its risk. This can be observed in the hourly and monthly patterns in Figure 2. Serving all customer groups will flatten the consumption and make it more economical than serving a single customer with greater load swings.

As a SOS supplier structures a response to serve FRS, it factors in the possibility that load may deviate from average expectations. Consequently, whenever load deviates from the average, it is commonly associated with

[14] For a broader description of ancillary services see https://www.iso-ne.com/markets-operations/markets

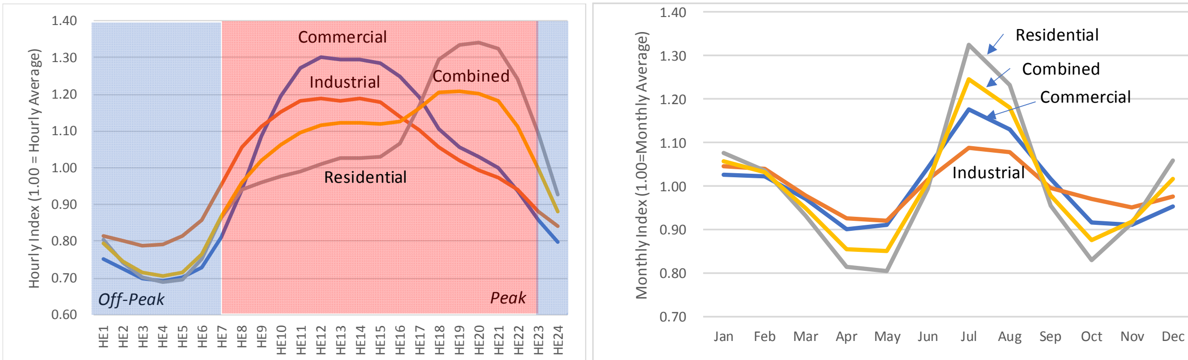
increases in costs. The SOS supplier's risk is based on its commitment to serve any amount of load at the same price.

FIGURE 1: LOAD SENSITIVITY TO WEATHER, JAN 2007-OCT 2017



Source: Concentric using data from National Grid and National Oceanic and Atmospheric Administration ("NOAA"). SOS load expressed in TWh. Heating and Cooling Degree days are expressed as cumulative over each month from Jan 2007 through October 2017.

FIGURE 2: HOURLY AND MONTHLY SEASONALITY OF CUSTOMER GROUP LOADS, JAN 2007-OCT 2017



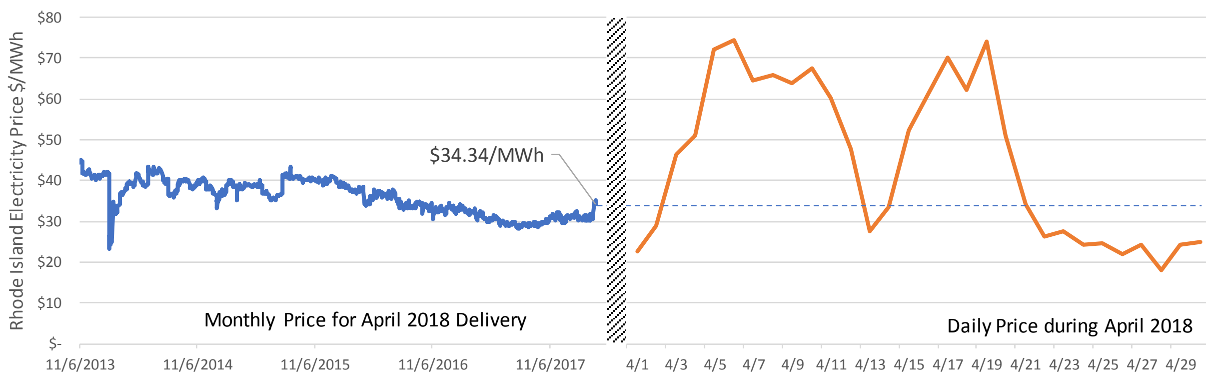
Source: Concentric using data for load from National Grid. Hourly or Monthly index normalizes consumption with respect to the average of all hours during the day, or for all months in a year. Hourly seasonality measured as hour ending ("HE").

Changes to Prices

In addition to variations in quantity, the cost to serve FRS will also fluctuate as a function of energy prices. The supplier may need to provide more (or less) energy than originally expected and will have to buy (or sell) energy at a price different from when it executed the transaction. As described in the section Changes to Quantity, prices often are higher than originally expected when the quantity (or actual electricity consumption) exceeds the original forecast due to weather. Conversely, it is common that prices are lower than originally expected when the quantity is less than the original forecast due to weather. The SOS supplier therefore may experience potential losses by buying additional electricity at higher prices while receiving lower prices from SOS customers, or by selling electricity at a price that is lower than its hedged prices when it executed the transaction.

For example, Figure 3 shows electricity prices in Rhode Island for April 2018 delivery priced months in advance (Blue) and for short-term delivery (orange). It indicates that prices could have been purchased for much of 2014 and 2015 for about $40/MWh and settled at $34.34/MWh. The settlement price is the price to be delivered for every day during April 2018. To support its economics, the SOS supplier will hedge by either buying in advance of the month, purchasing for next day delivery or a combination of both. In this illustrative case of April 2018, if the supplier decided not to purchase April 2018 in advance, it would have increased its price for serving the load by purchasing the commodity in the next-day delivery market. The prices for next-day delivery ranged from $18.18/MWh to $74.55/MWh for an average $44.92/MWh.

FIGURE 3: APRIL 2018 ELECTRICITY PRICES, 2013-2018



Source: Concentric using data from Chicago Mercantile Exchange and SNL. Daily prices (Orange) reflects electricity for next-day delivery. The Blue line represents the historical prices for April 2018 before expiration. The contract settled at $34.34/MWh.[15]

Changes in Load Profiles

The SOS supplier experiences uncertainty on the cost to serve the load if the consumption behavior of the customer group changes. This results in the supplier procuring (or selling) electricity at a different price than expected which may lead to losses. Figure 4 is a table of the Residential customer group hourly load shape (low, average and high) with color shading that illustrates the daily average variability of load by month. The intensity of the colors reflects higher (red) levels of consumption, lower (green) or average (yellow) levels of consumption. A SOS supplier is responsible for any level of consumption.

Load Migration

Another element that influences the risk premium is the possibility that customers may join or leave SOS and the supplier must incorporate that variability within the cost to serve the load. For instance, Figure 5 shows the monthly change in the number of customers for residential rate class (A-16) from Jan 2010 through August 2017. In addition to the number of customers and the load, the consumption pattern of the customers leaving/joining may also impact the cost to serve the load. For instance, an industrial customer with a flat consumption pattern (i.e. high load factor) that leaves SOS may change the cost to serve the remaining load by further accentuating its variability.

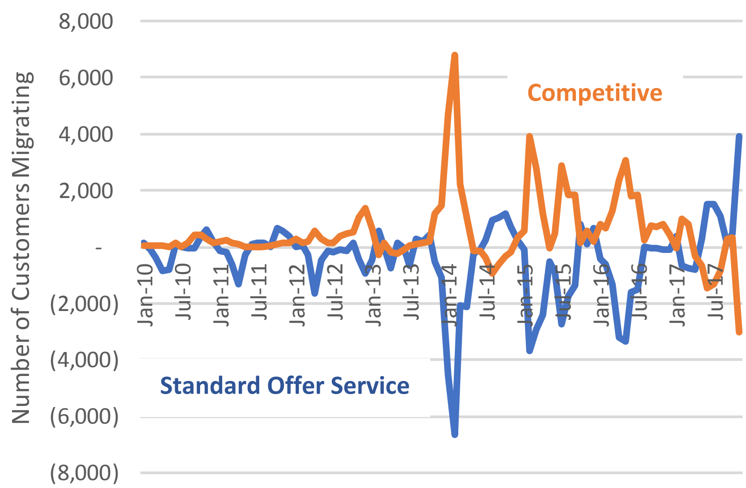
[15] Monthly price for April 2018 refers to the price of the contract for delivery during April 2018 that can be negotiated well in advance, or simply purchased at expiration ($34.34/MWh). It is calculated by combining prices for ISO New England Rhode Island Zone 5 MW Peak (56%) and Off-Peak Calendar-Month Day-Ahead LMP Futures (44%) using CME's trading codes "U4" and "U5". Daily price refers to prices for Rhode Island negotiated one day in advance of delivery and it is calculated by combining peak (56%) and off-peak (44%) ISO-NE. Z. RHODEISLAND day ahead prices.

FIGURE 4: TYPICAL DAILY VARIABILITY OF RESIDENTIAL LOAD SHAPE (MW), 2011-2017

	Low	Average	High
Jan	18	27	39
Feb	16	24	35
Mar	15	24	34
Apr	12	20	27
May	12	20	28
Jun	13	24	34
Jul	19	34	50
Aug	18	32	48
Sep	15	24	35
Oct	13	21	32
Nov	14	22	32
Dec	17	26	37

Source: Concentric using data from National Grid.

FIGURE 5: MONTHLY NUMBER OF RESIDENTIAL CLIENTS MIGRATING TO/FROM COMPETITIVE AND STANDARD OFFER SERVICE



Source: Concentric using data from National Grid for Residential Customers (A-16). The Figure depicts the monthly change in number of customers in the Standard Offer Service and those that have chosen a competitive supplier.

Capacity

The SOS supplier's capacity costs and the capacity revenue it receives may differ for several reasons as highlighted below:

Conversion to Consumption Rate

After a supplier calculates estimated capacity costs for a transaction, it must convert the costs from a $/MW-month to a $/MWh format to include in a FRS price. To make this conversion in units, the supplier divides the estimated capacity costs by the transaction's expected load and includes it in the fixed price. In the event the actual load equals the estimated load, the $/MWh fixed price will exactly compensate the supplier for its estimated capacity costs. However, if the actual load is less than the estimated load, the payments from the committed fixed price will be less than the supplier's estimated capacity costs, resulting in a financial loss. The Changes to Quantity and Changes in Load Profiles sections describe volatility in load from expectations that contribute to the uncertainty in recovery of capacity costs from customers.

Expected Capacity Payments

The estimated capacity-related costs may change with time and may be different when the SOS supplier pays for it as compared to when the supplier submitted the bid. The expected capacity payments (FCM Payments) associated with each SOS customer group is equal to the product of the expected FCM charges and the total expected Customer Load Obligation ("CLO") for each customer group. The FCM charges are composed of the Net Regional Clearing Price ("NRCP"), Capacity Transfer Rights ("CTR") charges, and Peak Energy Rent ("PER") adjustments. The NRCP is different for each capacity zone and is essentially the price the Load Serving Entities ("LSEs") pay to the resources that have cleared the FCA. CTRs are a mechanism to distribute excess revenues resulting from different payment rates between capacity zones. This situation results when one or more capacity zones are constrained.[16] PER is a payment adjustment made to reflect energy market revenues earned by resources during high priced hours. PER reduces the total FCM charges that a load pays.[17] It is important to note that the SOS supplier will not know the exact FCM charges incurred until after the end of each month. Therefore, a SOS supplier only has information on estimated FCM charges (i.e. NRCP, CTR charges, and PER adjustments) while preparing their bid.

For each month and capacity zone, LSEs have capacity responsibilities called the CLO, which is calculated as their share of the total Capacity Supply Obligation ("CSO") purchased in the FCA, based on their contribution to the system peak load from the previous year. Resources that clear in the FCA acquire a CSO, a physically and financially-binding obligation to provide the cleared amount of capacity. The initial CSO values established in the FCA can later change for a variety of reasons including the annual and monthly Reconfiguration Auctions ("RAs"), bilateral transactions between resources and termination of resource supply obligations.

A LSE's monthly CLO is primarily based on its monthly calculated Capacity Requirement.[18] A LSE's Capacity Requirement in a capacity zone for each month is equal to the product of the Capacity Zone Capacity

[16] ISO NE, Monthly Market Operations Report, December 2017.
[17] PER adjustments were eliminated from FCA effective June 1, 2019 (FCA 10).
[18] LSE's CLO is equal to the LSE's Capacity Requirement adjusted for Hydro-Quebec Interconnection Capability Credits (HQICC), CLO bilateral transactions, and Self-supply MW.

Requirements and the ratio of the LSE's contribution to the annual system peak from the calendar year prior to the start of the capacity period to the contribution of all LSEs in that capacity zone to the annual system peak from the calendar year prior to the start of the capacity period. The Capacity Zone Capacity Requirement is equal to the product of the system-wide CSO and the ratio of Capacity Zone's Peak Contribution to the system peak from **two** calendar years prior to the start of the capacity period and the system peak from **two** calendar years prior to the start of the capacity period. Therefore, the LSE's monthly CLO is dependent on a variety of factors including system-wide CSO, capacity zone CSO, LSE's historical peak, Capacity Zone's historical peak, and system-wide historical peak. Even though the CLO calculations are primarily based on historical peaks, for certain future months, the SOS supplier will have to predict the system-peak, capacity zone's contribution to that peak, as well as SOS customer's contribution to that peak.

Uncertainty in Expected Capacity Payments

The major drivers of the uncertainty associated with total expected FCM payments for a SOS supplier are:

1. Changes to NRCP
2. Changes to CSO
3. Changes to PER Adjustments
4. Changes to CLO.

The forecasted NRCP can change for a variety of reasons. As more information becomes available and as the date to make capacity payments gets closer, the NRCP might change due to clearing prices in annual and monthly Reconfiguration Auctions. As mentioned above, the CSO can change due to a variety of reasons including the annual and monthly Reconfiguration Auctions, bilateral transactions between resources, ISO-NE participation in reconfiguration auctions, and termination of resource supply obligations. As a CSO changes, the total payment required to compensate the supply resources changes, and as a result, the NRCP will also change.

The forecasted PER adjustment is dependent on energy prices and will vary depending on energy prices. Therefore, the SOS supplier will assess future energy prices and their potential impact to the PER adjustments.

Finally, the changes to CLO are an important risk factor that must be considered by a SOS supplier. The CLO for each SOS customer group can primarily change due to three factors: 1) changes to the CSO because the calculation of CLO for each LSE is based directly on the CSO, 2) customer migration, and 3) change in customer usage patterns.

Combined Risks

The previous sections outlined a series of individual risks that may change the cost to serve the load, and that the SOS supplier will have to consider as it develops its bid. In addition to the effect of individual risks, the risk of a combined occurrence of individual risks may also affect the cost to serve the load. Through modern portfolio theory, the combined risk is likely going to be lower than the sum of the individual risk exposures, contingent on the probability that several events may occur simultaneously. For instance, the spikes in electricity prices do not necessarily always occur when electricity consumption peaks. In general, the aggregate effects of the risks are a non-linear combination of the individual risks and the relationships between the risks.[19]

[19] For a more technical discussion see Elton, Edwin J. and Martin J. Gruber. (1991). Modern Portfolio Theory and Investment Analysis. Fourth Edition. Chapter 2. John Wiley and Sons, Inc.

Structuring a Bid to Contain the Risks

When a SOS supplier participates in an RFP and submits a bid to serve FRS, it protects its economics (i.e. hedges) with assets or purchases that align with the commitments it is making to National Grid. The estimated cost to serve the load can be mostly hedged by combining Forward or Futures contracts for energy and estimating costs associated with ancillary services and capacity. The sources of risk identified in the previous sections can be estimated by the valuation of Options to cover the risk of the load/prices being higher than expected (i.e. buying a call Option) and the risk of the load/prices being lower than expected (buying a put Option).

We have already addressed how the SOS supplier will support its bid by buying energy contracts in advance (see description of Full Requirements Service). To estimate the cost of the risks addressed in section "Nature of Risk Premium", Concentric implemented an option-theory approach that effectively prices the aggregate effect of the risk. To understand the Option structure utilized, first we need to state some features of Options:

1) In finance, an Option is a contract which gives the buyer (the owner or holder of the Option) the right, but not the obligation, to buy or sell an underlying asset or instrument at a specified strike price;
2) A call Option gives the buyer the right but not the obligation to purchase the asset at a pre-arranged price;
3) A put Option gives the buyer the right but not the obligation to sell the asset at a pre-arranged price;
4) Since the Options give the buyer (call or put) a right (to buy or sell), the buyer is obligated to pay a premium;
5) The premium represents a fair price for the risk of deviating from the strike price. It represents a compensation that considers existing market conditions, an expectation of change (i.e. volatility), and the time for the event to occur.

Theoretically, and given the features for Options outlined above, the SOS supplier may complement its purchase of Forward positions to address the expected level of cost of service by purchasing a call Option and purchasing a put Option at the same price as the market conditions when the bid is placed. By purchasing the call Option, the supplier is protecting against the possibility that the load/price will be higher than expected by enabling it to buy the commodity at the same price as the bid price. By purchasing the put Option, the supplier is protecting itself against the possibility that load/price will be lower than expected and enabling it to sell the commodity at the same price as the bid. In lieu of executing Options, the supplier may include the call and put premiums in its SOS bids as an estimate for the risk premium to protect from financial losses.

The methodology of pricing Options at the same price as the bid (also called "At-the-Money" or "ATM") does not necessarily reflect actual Option transactions that can be implemented in the market. The construct nevertheless represents the probability-weighted cost of the outcome occurring. The traditional Option theory is structured around the variability of one asset (say for instance energy prices), but the approach implemented to estimate the risk was based on the combined outcome of the cost to serve the load (e.g. price times quantity). Actual pricing of the Options was done by the close-form Black and Scholes Option pricing formula.[20] Empirical tests have shown

[20] The Black-Scholes or Black-Scholes-Merton model is a mathematical model widely used in financial markets to calculate the theoretical price (i.e. premium) to purchase or sell an option contract.

that the Black-Scholes price is close to the ex-post observed prices and shortcomings such as dealing with irregularities in volatility does not critically affect the purpose of the estimation.[21]

In practical terms, Option premium depends on several factors.[22] Since the risk of variations in the cost to serve the load come from different sources (as identified above), the Option pricing methodology was adapted to consider a portfolio effect of risks according to the following logic:

1) Date of evaluation. This is the time at which the premium is evaluated which, in this case, is the same date as when the bid was submitted;
2) Date of expiration. Reflects the delivery month for the bid;
3) Price of commodity. It is the price at the time of the bid and the expected load forecast at the time of the bid. The expected value is based on the combined cost to serve the load at several levels. For instance, the expected value for the energy component is the combined value of multiplying price and quantity. Alternatively, the expected value for a serving the entire load in terms of energy, capacity and ancillary services is a combination of quantities and prices for each of the elements;
4) Exercise price. Since the supplier is trying to protect against the possibility of the cost to vary from current expectations, the exercise price is the same as the expected price;
5) Annualized volatility. This is approximated by analyzing the historical distribution of the expected value. For instance, volatility is approximated by looking at the maximum and minimum values of the expected cost and then measuring this value with respect to the expected;
6) The standard deviation is approximated by analyzing the maximum and minimum values of the historical cost. This provides two measures of standard deviations to reflect increases or decreases to the expected cost to serve the load; and
7) The expected load is based on National Grid's forecast.

The purpose of this document is to provide an intuitive understanding of how the Option pricing theory works. With that frame in mind, there are several features that make it an appealing structure to measuring the risk premium:

- The risk increases as time increases and this is reflected in higher risk premium;
- As uncertainty increases, the premium increases; and
- The combined risk effect (for example, both prices and quantity increasing dramatically) is less than if the risk of each item was calculated individually and summed together because it is unlikely that extremely unfavorable events will occur at the same time.

[21] See for instance Bodie, Zvi; Alex Kane; Alan J. Marcus (2008). Investments (7th ed.). New York: McGraw-Hill/Irwin. ISBN 978-0-07-326967-2.
[22] See for instance Kaminski, Vincent (2012). Energy Markets. Risk Books. Chapter 4.

Summary Findings

When National Grid issues an RFP for FRS, the fixed price ($/MWh) will include risk premiums to address the economic consequences that the cost to serve the load may fluctuate. The premiums are meant to address several market-related risks including variations in prices, quantities, and changes in system-wide coincident peak. A supplier will typically protect against unfavorable changes to the cost to serve the load by purchasing energy in advance to match the commitment in the FRS. The costs of ancillary services and capacity are often left unhedged because the liquidity is limited (such as the case for ancillary services) or because there is no effective hedging mechanism (such as for capacity).

The risk premium for a fixed capacity price included in the FRS was calculated by analyzing the cost of the individual elements being procured, and by modeling the economic consequences of changes to the cost to serve the load. The approach involved calculating the risk for each individual element, and the compounded risk of serving all unknown cost fluctuations. The approach follows modern portfolio theory that estimates the risk of a portfolio as a non-linear combination of its elements and implemented by Option pricing theory. The result is an analysis that replicates how a SOS supplier would price a service such as the one demanded under the FRS. It differentiates between the sources of risk, and how the risk aggregates across different customer classes and product offerings that National Grid may encounter in future FRS transactions.

The following is a list of summary observations resulting from such analysis:

1) Removing capacity charges from the FRS will decrease the risk premiums without unduly exposing customers to market risks;
2) Bundling capacity with energy and ancillary services effectively groups cost elements with a very different cost, risk, and settlement structures;
3) The capacity market is an administrative construct whose uncertainty differs substantially from market-related volatility in energy or ancillary services products;
4) Unlike energy costs that suppliers can hedge, capacity costs are not effectively market costs. The risk premium reflects the risk of the administrative process, and not of the actual market prices;
5) The actual costs that a supplier will pay for capacity are determined after the settlement month occurs. When compared to energy markets that derive uncertainty of not knowing what price will be at settlement (i.e. in the future), capacity markets do not exhibit such exposure;
6) By bidding for capacity prices within an all-in price referenced in terms of $/MWh, the risk premium for capacity is influenced by the number of MWhs served. Given the current structure, the risk premium of capacity is influenced by the risk of electricity consumed;
7) Excluding capacity from the FRS bids may allow more suppliers to participate in the FRS RFPs;
8) Understanding the risk premiums included in FRS bids exclusive of capacity involves many assumptions as to how the supplier will structure its supply portfolio, its risk appetite, profit goals, aggressiveness in the bid and how it wishes to distribute the risk across the different customer classes. It is therefore unrealistic to determine a unique premium for all FRS bids.
9) Under reasonable assumptions, the estimated capacity risk premium in the January 10, 2018 RFP for the load-weighted risk premium for industrials for 3-month was $0.30/MWh. For 24-month period, the load-weighted risk premium for residential was $2.56/MWh and $3.33/MWh for Commercial.

Acronyms

ATC	Around the clock
CDD	Cooling Degree Days
CLO	Capacity load obligations
CME	Chicago Mercantile Exchange
CSO	Capacity supply obligations
CTR	Capacity Transfer Rights
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FRS	Full Requirement Service
Forward	Refers to a non-standardized agreement between two parties to buy or sell a product (such as electricity) at a pre-agreed price and for delivery sometime in the future
Future	Refers to a standardized contract to buy or sell a product (such as electricity) at a pre-agreed price and for delivery sometime in the future
HDD	Heating Degree Days
HE	Hour Ending
HQICC	Hydro Quebec Interconnection Capability
ISO-NE	Independent System Operator New England
LSE	Load Serving Entity
MPT	Modern Portfolio Theory
NRCP	Net Regional Clearing Price
Option	Intuitively, it refers to the contract where two parties agree to execute a contract if a certain (uncertain) condition happens in the future. To have the right to execute this contract, the buyer pays a premium up front, but it is not obligated to execute the contract unless the condition materializes
PER	Peak Energy Rent
PUC	Public Utilities Commission
RA	Reconfiguration Auction
SNL	A subscription-based data vendor that gathers information from several sources (https://platform.mi.spglobal.com)
SOS	Standard Offer Service

Division 1-3

Request:

Please provide the tables that appear on page 9 & 10 of the testimony of Witness Stephen A. McCauley in native format and, as applicable, in Excel format with formulae intact.

Response:

Please see Confidential Attachment DIV-1-3, which is a working Excel version of the tables presented on pages 9 and 10 of the Direct Testimony of Stephen A. McCauley.

Pursuant to PUC Rule 1.2(g), the Company is seeking confidential treatment of the Excel version of Confidential Attachment DIV-1-3.